Legislation and Regulations

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Introduction

Because analyses by the Energy Information Administration (EIA) are required to be policy-neutral, the projections in this *Annual Energy Outlook 1999* (*AEO99*) are based on Federal, State, and local laws and regulations in effect on July 1, 1998. The potential impacts of pending or proposed legislation and sections of existing legislation for which funds have not been appropriated are not reflected in the projections.

Federal legislation incorporated in the projections includes the Omnibus Budget Reconciliation Act of 1993, which adds 4.3 cents per gallon to the Federal tax on highway fuels [*1*]; the National Appliance Energy Conservation Act of 1987; the Clean Air Act Amendments of 1990 (CAAA90); the Energy Policy Act of 1992 (EPACT); the Outer Continental Shelf Deep Water Royalty Relief Act of 1995; and the Tax Payer Relief Act of 1997. *AEO99* also incorporates regulatory actions of the Federal Energy Regulatory Commission (FERC), including Orders 888 and 889, which provide open access to interstate transmission lines in electricity markets, and other FERC actions to foster more efficient natural gas markets. State plans for the restructuring of the electricity industry and State renewable portfolio standards are incorporated as enacted.

CAAA90 requires a phased reduction in vehicle emissions of regulated pollutants, to be met primarily through the use of reformulated gasoline. In addition, under CAAA90, annual emissions of sulfur dioxide by electricity generators are, in general, capped at 8.95 million short tons a year in 2010 and thereafter, although "banking" of allowances from earlier years is permitted. CAAA90 also calls for the U.S. Environmental Protection Agency (EPA) to issue standards for the reduction of nitrogen oxide (NO_x) emissions, leading to regulations that impose limits on electricity generators for NO_x emissions. The impacts of CAAA90 on electricity generators are discussed in "Market Trends" (see page 86).

The provisions of EPACT focus primarily on reducing energy demand. It requires minimum building efficiency standards for Federal buildings and other new buildings that receive federally backed mortgages. Efficiency standards for electric motors, lights, and other equipment are required, and owners of fleets of automobiles and trucks are required to phase in vehicles that do not rely on petroleum products.

The projections include only those equipment standards for which final actions have been taken and which specify efficiency levels, including the refrigerator standard that goes into effect in July 2001. *AEO98* included a discussion of proposed actions, but no additional standards have been finalized.

Climate Change Action Plan

The *AEO99* reference case projections include analysis of provisions of the Climate Change Action Plan (CCAP)—44 actions developed by the Clinton Administration in 1993 to achieve the stabilization of greenhouse gas emissions (carbon dioxide, methane, nitrous oxide, and others) in the United States at 1990 levels by 2000. CCAP was formulated as a result of the Framework Convention on Climate Change, which was adopted at the United Nations on May 9, 1992, and opened for signature at Rio de Janeiro on June 4. As part of the Framework Convention, the economically developed signatories, including the United States, agreed to take voluntary actions to reduce emissions to 1990 levels.

Energy combustion is the primary source of anthropogenic (human-caused) carbon emissions. *AEO99* estimates of emissions from fuel combustion do not include emissions from activities other than fuel combustion, such as landfills and agriculture, nor do they take into account sinks that absorb carbon, such as forests. Of the 44 CCAP actions, 13 are not related either to energy combustion or to carbon dioxide and, consequently, are not incorporated in the analysis. The projections do not include any other carbon mitigation actions that may be enacted as a result of the Kyoto Protocol, agreed to on December 11, 1997 (see "Issues in Focus," page 30, for further discussion).

Climate Wise and Climate Challenge are two programs cosponsored by EPA and the U.S. Department of Energy (DOE) to foster voluntary reductions in emissions on the part of industry and electricity generators, as reported in the EIA publication *Mitigating Greenhouse Gas Emissions: Voluntary Reporting* [*2*]. The *AEO99* reference case includes analysis of the impacts of both programs (see Appendix G).

Extension of Outer Continental Shelf Leasing Moratoria

On June 12, 1998, the President extended the current moratoria on new leases for offshore oil drilling on the U.S. Outer Continental Shelf (OCS) through June 30, 2012. The extension withdraws from possible leasing the areas of the OCS currently under moratoria in the following OCS planning areas: the North Aleutian Basin; Washington-Oregon; Northern, Central, and Southern California; South Atlantic; Mid-Atlantic; North Atlantic; and sections of the Eastern Gulf of Mexico. Also withdrawn were those areas of the OCS designated as marine sanctuaries under the Marine Protection, Research, and Sanctuaries Act of 1972. The sanctuaries range in size from less than 1 square mile to more than 5,300 square miles [*3*]. The extension of OCS moratoria does not affect any current leases. Because the *AEO99* forecast does not include production from restricted areas, the extension has no impact on the projections.

Regulation of Natural Gas Transportation Services

On July 29, 1998, the Federal Energy Regulatory Commission (FERC) proposed changes in its regulations governing interstate natural gas pipelines. The purpose of the changes is to allow more flexibility and competitiveness in the market for short-term transportation services. Under the proposed changes, cost-based regulation would be replaced by policies intended to maximize competition, mitigate the ability of firms to exercise residual monopoly power, and provide opportunities for greater flexibility in the provision of pipeline services. Pipelines would be permitted to negotiate rates and terms of service. The Commission is also seeking comments on its pricing policies for the existing and long-term market and for new capacity. Comments on both proposed changes and existing policy are due on January 22, 1999 [*4*]. Although the specific changes proposed by the FERC are not included, the *AEO99* reference case does assume an increasingly competitive market for natural gas transportation services.

Extension of Ethanol Tax Credit

The Federal Highway Bill of 1998 included an extension of the ethanol tax credit, which has been granted since 1986 and was scheduled to expire in 2000. The tax credit is currently 54 cents per gallon and applies to ethanol and the ethanol portion of the gasoline additive ethyl tertiary butyl ether (ETBE). The Highway Bill extends the tax credit through 2007 but specifies 1-cent-per-gallon reductions in 2001, 2003, and 2005. Ethanol and ETBE may be blended into gasoline to boost either octane or oxygen content. The tax credit effectively reduces the cost of ethanol and ETBE, making them more attractive for blending with gasoline. *AEO99* assumes that the ethanol tax credit will not expire in 2007 but will continue at the nominal level of 51 cents per gallon. The benefit of the credit is eroded by inflation over time, however, reducing its value to 27 cents per gallon (in 1997 dollars) by 2020.

Tier 2 Vehicle Standards

The Clean Air Act Amendments of 1990 (CAAA90) set "Tier 1" exhaust emission standards for carbon monoxide (CO), hydrocarbons, nitrogen oxides (NO_x), and particulate matter (PM) for light-duty vehicles and trucks beginning with model year 1994. CAAA90 also required the U.S. Environmental Protection Agency (EPA) to study further "Tier 2" emission standards that would take effect between model years 2004 and 2007. EPA provided a Tier 2 study to Congress in July 1998 [*5*] and is expected to publish a Notice of Proposed Rulemaking for the Tier 2 standards early in 1999.

Air quality projections included in the EPA's Tier 2 study indicate that the existing Tier 1 vehicle emissions standards, and the implementation of the voluntary National Low Emissions Vehicle (NLEV) program set for implementation between 1999 and 2001, will not be enough to achieve attainment of National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter (PM) between 2007 and 2010. The study concludes that further emissions reductions for volatile organic compounds (VOCs), NO_x, and PM will be needed to move many areas of the country, and the Nation as a whole, toward compliance. In addition, the study concludes that more stringent Tier 2 vehicle emissions standards are a cost-effective means of improving air quality. The study also examined the feasibility of technologies that would reduce emissions from light-duty vehicles and trucks, ranging from advanced engine designs to improved exhaust after-treatment systems.

The Tier 2 study emphasizes the importance of the relationship between emissions reduction technology and gasoline sulfur content. Sulfur reduces the effectiveness of the catalyst used in the emission control systems of advanced technology vehicles, increasing their emissions of hydrocarbons, carbon monoxide, and NO_x. Because of the link between sulfur and emissions, the EPA is developing proposed restrictions on gasoline sulfur content in connection with the Tier 2 standards.

Tier 2 standards and restrictions on gasoline sulfur are not reflected in the *AEO99* reference case because the end result of the upcoming rulemaking process is unknown. Analysis of the potential costs of reducing sulfur in gasoline is included in "Issues in Focus" (see page 29).

Low-Emission Vehicle Program

The Low Emission Vehicle Program (LEVP) was originally passed into legislation in 1990 in the State of California. It began as the implementation of a voluntary opt-in pilot program under the purview of CAAA90, which included a provision that other States could opt-in to the California program and achieve lower emissions levels than required by CAAA90. Both New York and Massachusetts chose to opt-in to the LEVP program, implementing the same mandates as California.

The LEVP was an emissions-based policy, setting sales mandates for three categories of low emission vehicles according to their relative emissions of air pollutants: low emission vehicles (LEVs), ultra-low emission vehicles (ULEVs), and zero emission vehicles (ZEVs). The only vehicles certified as ZEVs by the California Air Resource Board were dedicated electric vehicles [*6*].

The LEVP was originally scheduled to begin in 1998 with a requirement that 2 percent of the State's vehicle sales be ZEVs, increasing to 5 percent in 2001 and 10 percent in 2003. In California, however, the beginning of mandated ZEV sales was rolled back to 2003, because it was determined that ZEVs would not be commercially available in sufficient numbers or at sufficiently competitive cost to allow the targets to be met. In Massachusetts and New York, after several years of litigation, the Federal courts overturned the original LEVP mandates in favor of the same deferred schedule adopted by California.

Ozone Transport Rule

Over the past several years, extensive effort has gone into examining the impact of interstate ozone emissions. Many of the States in the Northeast believe that they will not be able to reduce their ozone concentrations to required levels unless out-of-state emissions are also reduced. The Ozone Transport Assessment Group (OTAG), made up of State, Federal, utility, and nonutility representatives, was established to analyze the issue. OTAG's analyses suggested that nitrogen oxide (NO_x) emissions from power plants in some midwestern States are having an impact on ozone concentrations in downwind northeastern States [*7*].

In response to OTAG's recommendations, the EPA issued a notice of proposed rulemaking (NOPR) on November 7, 1997 [*8*]. In the NOPR, EPA established summer season NO_x emission limits (referred to as budgets) for electricity power plants in 22 eastern and midwestern States. Originally the NOPR set the NO_x limit for the summer season (May 1st through September 30th) for the 22 States at 489,000 tons, but the limit was raised to 563,800 tons in the final rule issued on September 24, 1998 (Table 2). The change resulted from technical corrections made by the EPA to the population of sources of NO_x emissions in the baseline data from which the budgets were derived.

The NOPR and its supplement require States to develop plans to meet their NO_x emission budgets in 2003 and beyond. The EPA hopes to encourage States to participate in a NO_x "cap and trade"

Table 2. Summer season NO_x emissions budgets for 2003 and beyond (thousand tons per year)

State	NO_x budget	State	NO_x budget
Alabama	37.4	New Jersey	8.8
Connecticut	3.3	New York	24.1
Delaware	3.6	North Carolina	34.6
District of Columbia	0.0	Ohio	46.8
Georgia	37.5	Pennsylvania	46.2
Illinois	37.9	Rhode Island	1.1
Indiana	47.4	South Carolina	18.0
Kentucky	38.4	Tennessee	23.7
Maryland	13.9	Virginia	19.3
Massachusetts	10.3	West Virginia	33.5
Michigan	35.0	Wisconsin	19.0
Missouri	24.0	**Total**	**563.8**

program, under which the EPA would issue NO_x emission allowances to power plant operators and other large sources. Each allowance would permit the holder to emit one ton of NO_x and could either be used for the facility to which it was originally allocated or sold.

As with the sulfur dioxide (SO_2) allowance program created by CAAA90, the goal of the NO_x cap and trade program would be to reduce compliance costs through efficient market mechanisms. The program is meant to encourage reductions in NO_x emissions from facilities where they can be made relatively inexpensively, while providing the option of allowance purchases for facilities where the costs of reducing emissions would be higher.

Power plant operators have several options for reducing NO_x emissions, including low-NO_x burners, other combustion controls (flue gas recirculation, staged combustion, reduced oxygen, etc.), selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR). In addition, co-firing a coal plant with natural gas is also an option. In general, combustion controls (including low-NO_x burners) are relatively inexpensive and reduce uncontrolled NO_x emissions by 40 to 50 percent. In contrast, SNCR and SCR technologies are more expensive, but they reduce NO_x emissions by 60 to 80 percent. The option chosen for each plant will depend on its uncontrolled emission rate, boiler type, size, and operational economics.

In the *AEO99* reference case, a mix of options is chosen. By 2020, combustion controls alone are expected to be added to 10 gigawatts of capacity, SNCR units to 96 gigawatts, and SCR units to 111 gigawatts. The annualized cost of the control technologies is projected at $2 billion—very small in comparison with the approximately $200 billion that consumers spend annually on electricity purchases. However, many of the same units expected to add NO_x reduction equipment, primarily coal steam plants, would also be affected if efforts to reduce carbon emissions were undertaken in the future. It may be economical to add NO_x control equipment to such units now, but the addition of carbon reduction requirements could make retirement a more attractive option for many units. A recent EIA study [*9*] found that U.S. efforts to meet the carbon reduction targets of the Kyoto Protocol could result in the retirement of many coal-fired power plants.

Mercury Emissions Data Collection

CAAA90, Section 112(n)(1)(A), required that the EPA prepare a study of hazardous air pollutants from steam generating units. A report on the results of the study was submitted to Congress on February 24, 1998. The key finding was that mercury emissions from coal-fired power plants posed the greatest potential for harm. The levels of mercury concentration in air or water were not found to be a problem; however, it was found that mercury can accumulate in some fish species, making them dangerous to consume in large amounts.

The role of mercury emissions from particular coal-fired power plants in the process is not clear, and the EPA has decided to collect additional data from power plant operators before determining whether their mercury emissions should be regulated. The draft data collection plan states that, beginning on January 1, 1999, the owners of coal-fired power plants 25 megawatts or larger will be required to collect weekly data on the mercury contents of the coal used and the stack emissions and to submit the data to the EPA quarterly. After collecting the data for 1 year, the EPA will determine whether mercury emissions regulations are needed.

National Ambient Air Quality Particulate Standard

AEO99 does not include the new fine particulate standard proposed in the EPA's revised National Ambient Air Quality Standards (NAAQS). The NAAQS created a new standard for fine particles, smaller than 2.5 micrometers in diameter ($PM_{2.5}$). The new health-based standard sets the exceedance limits for $PM_{2.5}$ at a 3-year annual arithmetic mean of 15 micrograms per cubic meter ($\mu g/m^3$) and a 24 hour standard of 65 $\mu g/m^3$ (99th percentile of concentrations in a year averaged over 3 years). The EPA is required to take several steps, however, before the standard can be enforced.

In a memorandum dated July 16, 1997, the President directed the EPA to determine within the next 5 years, based on review of scientific data, whether to revise or maintain the proposed standard. Thus, final standards will not be issued until July 2002, at the earliest. The States will then be given 3 years to develop plans to come into compliance and will have up to 10 years to reach the required concentration levels. As a result, without any changes, the earliest full compliance date would be 2015. As the data review progresses and compliance approaches begin to take shape, the fine particle standard may be included in future *AEO*s.

Hazardous Air Pollutant Standards

During 1998 the EPA proposed two new sets of national emissions standards for hazardous air pollutants (NESHAPs) under the authority of the Clean Air Act. The first proposed NESHAP would limit emissions of hazardous air pollutants (HAPs) from oil and natural gas production and natural gas transmission and storage facilities. The EPA has determined that such oil and gas facilities emit HAPs including benzene, toluene, ethyl benzene, mixed xylenes, and *n*-hexane.

The EPA expects the proposed NESHAP to reduce HAP emissions from oil and gas production by 57 percent and from natural gas transmission and storage by 36 percent [*10*]. The proposed NESHAP would require the installation of Maximum Achievable Control Technology (MACT) at more than 400 facilities involved in the production of oil and natural gas and the transmission and storage of natural gas. Another 500 production facilities may be required to install less stringent controls. The rule was proposed in February 1998 and is expected to be finalized in mid-1999 [*11*].

A second NESHAP, proposed in September 1998, would require petroleum refineries to reduce HAPs from process vents on catalytic cracking, catalytic reforming, and sulfur plant units. NESHAPs for other refinery processing units were set in August 1995 but did not include standards for these three processes. NESHAPs for the additional processes were recently proposed, because the EPA determined that they can be expected to emit a number of HAPs. The proposed standards are specifically aimed at reducing emissions of organics, sulfur compounds, inorganics, and particulate metals. The EPA estimates that refiners would invest approximately $173 million for the required MACT control equipment and about $43 million a year for related maintenance [*12*]. Potential changes that would be associated with the two NESHAP proposals are not included in the *AEO99* reference case.

Electricity Industry Restructuring

Despite several proposals, no comprehensive Federal electricity restructuring bill had been enacted as of early August 1998. Several bills were proposed, but no consensus could be reached. It is expected that new bills will be introduced early in 1999 in the 106th Congress. At the State level the situation is moving forward more rapidly. Nearly every State has undertaken some effort to review options for or implement changes in the structure of the electricity business, and a number of States have taken regulatory or legislative action [*13*]. The critical issues in most States are whether and when to allow consumers to choose their electricity suppliers, how to deal with utility stranded costs, and what sort of market structure would most encourage competition.

Twelve States have enacted restructuring legislation and are moving toward letting consumers choose their suppliers over the next several years. Six other States have comprehensive regulatory orders in place. Barring changes, in the twelve States with legislation in place, consumers will be free to choose their electricity suppliers starting some time between 1998 and 2004 [*14*]. Most of the twelve call for consumer choice to be phased in over several years. Generally, larger industrial customers are given choice earlier, while smaller commercial and residential customers are given choice later.

Three States—California, Rhode Island, and Massachusetts—plan to allow all their consumers to choose their suppliers by the end of 1998. California opened the market to all customers on March 31, 1998 [*15*]. Consumers in California now receive bills with separate charges for the services provided. Depending on the type of customer, they could include fees for energy services, transmission services, distribution services, a competitive transition charge, a nuclear decommissioning charge, public program charges, fixed transition charges, and other charges.

The competitive transition charges—associated with paying utilities for “stranded” investments they made to serve customers that may not be recovered in a competitive market—will continue for only a fixed period of time, probably several years. All the services may still be provided by the incumbent utility, or each may come from a different company, depending on the decisions made by the customer. The situation is similar in Rhode Island and Massachusetts, where all customers are able to choose their suppliers as of 1998.

In all three States, decisions have been made about the level of stranded cost recovery allowed and the rate reductions required over the next few years, but some of the decisions are being challenged. Although ballot referendums in California and Massachusetts in the November 1998 elections failed, future challenges are likely.

The three States are taking a variety of approaches to stranded cost recovery [*16*], differing in the estimation methodology, level of recovery allowed, recovery mechanism, and length of recovery. For example, in California utilities are to be given the opportunity to recover prudently incurred stranded costs. The costs will be recovered through a competitive transition charge and financed through the issuance of rate reduction bonds. Most of the costs will be recovered by the end of 2001, but the bonds mature over a 10-year period. In Rhode Island a 2.8 cent per kilowatthour nonbypassable transition charge will be collected through December 2009. In addition, utilities are required to divest a portion of their generating assets, and the transition charge will be adjusted if market conditions warrant.

Similarly, in Massachusetts, stranded costs will be recovered over 5 to 10 years, power plant divestiture is encouraged, and the transition charge will be adjusted to reflect market conditions. The actual amount of stranded costs each utility will be able to collect in these States will depend on the price of electricity that evolves in the market and the ability of the utility to reduce its operating costs.

Throughout *AEO99*, all regions of the country are treated as being competitive in wholesale markets (no new rate-based capacity). In five regions—California, New York, New England, the Mid-Atlantic Area Council (Pennsylvania, Delaware, New Jersey, and Maryland), and the Mid-America Interconnected Network (Illinois and parts of Wisconsin and Missouri)—electricity is priced competitively, based on marginal costs, at the retail level. Competitive forces are assumed to continue to put pressure on electricity producers to reduce their costs, and, as a result, nonfuel operations and maintenance costs are assumed to decline by 25 percent over the next 10 years from their current level. It is also assumed that plants will be retired when it is no longer economical to maintain them. In other words, new capacity is built to retire existing capacity and meet growth in the demand for electricity.

Renewable Technologies

In several States, electricity restructuring legislation includes provisions to stimulate the development of renewable generating technologies for wind, solar, geothermal, and biomass plants. Many believe that these technologies may not succeed in a competitive market where investment decisions are based solely on direct market costs. In general, renewable technologies are more expensive than fossil-fueled alternatives (particularly new natural-gas-fired combined-cycle plants), and it is expected that few would be built in a competitive market.

Advocates of renewable technologies believe that their environmental benefits outweigh their higher costs, and that the costs could fall significantly if demand increased enough to allow manufacturers to take advantage of economies of scale in production. In other words, if they could be assured of selling more units, manufacturers would invest in larger, more efficient facilities and lower the per-unit costs of production.

To encourage the development of renewable technologies, some States are using a renewable mandate, specifying that a certain amount of renewable capacity must be built. Others are using a public benefit fund (PBF) financed by a small fee collected from customers for each kilowatthour of electricity purchased. The revenue is to be used to support a variety of programs, including low-income support, demand-side management, and renewable development.

A third approach is the renewable portfolio standard (RPS), which specifies that a percentage of the electricity generated (or sold) in the State must be produced by qualifying renewable power plants. In most of the bills, qualifying renewables include all renewable facilities other than hydroelectric plants and municipal solid waste. The RPS system can operate as a tradable credit system in which anyone operating a qualifying renewable plant will be issued credits equal to its generation. If the RPS requirement is 5 percent, the operator will only need to keep credits equal to 5 percent of the plant's output. The rest can be sold to suppliers selling power produced from nonqualifying facilities. Examples of State RPS programs include the following:

- Arizona has implemented a program to encourage solar power development. The program requires that 0.5 percent of new electricity sales come from solar plants in 1999 and 2000, and 1 percent thereafter.
- In Connecticut, new resources are broken into two classes. Class 1 includes sustainable biomass, fuel cells, landfill gas, solar, and wind power. Class 2 includes other biomass, municipal solid waste, and conventional hydroelectricity. The program requires that by 2001 class 1 resources provide a minimum of 0.75 percent of licensed utility output, and that another 5.5 percent be provided by a mix of class 1 and class 2 resources. By 2009, the class 1 minimum requirement grows to 6.0 percent, and an additional 7.0 percent must come from a mix of class 1 and class 2 resources.
- Massachusetts has instituted a program that requires an increase in the share of sales coming from qualifying sources (biomass, landfill gas, fuel cells, conventional hydroelectricity, ocean thermal, solar, and wind) from 1 percent in 2003 to 15 percent by 2020.
- In Nevada, the required share for nonhydroelectric renewables starts at 0.2 percent in 2001 and increases 0.2 percentage points per year until reaching 1 percent.
- In Maine, a much larger share is required. By March 2001, 30 percent of total retail sales must be generated from biomass, fuel cells, geothermal, small hydroelectric, municipal solid waste, solar, or wind.

In addition to these programs, States such as California, Colorado, Iowa, Minnesota, New York, and Wisconsin have implemented renewable mandates requiring specific generation or capacity levels or other "green power initiatives."

In order to represent these State programs in the *AEO99* projections, estimates were made of the amounts and types of capacity each of the State programs would encourage. Accordingly, new plants with the appropriate technology, capacity, and start years were added to the inventory of plants available. (For example, the Arizona program is expected to encourage 80 megawatts of solar development.) In total, the various State RPS programs are expected to encourage just over 638 megawatts of new renewable capacity between 1999 and 2011. Wind (263 megawatts), solar (163 megawatts), and biomass (137 megawatts) are expected to account for the majority of the renewable capacity encouraged by State RPS programs.

State mandates and other requirements are expected to produce another 1,372 megawatts of new renewable capacity, with wind (1,017 megawatts), geothermal (149 megawatts), biomass (137 megawatts), and landfill gas (69 megawatts) making up most of the capacity. Finally, voluntary plans, such as green power initiatives, add another 67 megawatts—47 megawatts of wind capacity, 10 megawatts of photovoltaics, and 9 megawatts of landfill gas capacity.